



IADC/SPE 27432

3 1/2-in. Coiled Tubing: A First Run

M.L. Prestridge, ARCO Alaska Inc., and A.J. Mahoney, Schlumberger

SPE Members

Copyright 1994, IADC/SPE Drilling Conference.

This paper was prepared for presentation at the 1994 IADC/SPE Drilling Conference held in Dallas, Texas, 15-18 February 1994.

This paper was selected for presentation by an IADC/SPE Program Committee following review of information contained in an abstract submitted by the author(s). Contents of the paper, as presented, have not been reviewed by the Society of Petroleum Engineers or the International Association of Drilling Contractors and are subject to correction by the author(s). The material, as presented, does not necessarily reflect any position of the IADC or SPE, their officers, or members. Papers presented at IADC/SPE meetings are subject to publication review by Editorial Committees of the IADC and SPE. Permission to copy is restricted to an abstract of not more than 300 words. Illustrations may not be copied. The abstract should contain conspicuous acknowledgment of where and by whom the paper is presented. Write Librarian, SPE, P.O. Box 833836, Richardson, TX 75083-3836, U.S.A. Telex, 163245 SPEUT.

ABSTRACT

The world's first string of 3-1/2" coiled tubing was run as completion tubing in an exploration well on the North Slope of Alaska. The tubing was run as a single permanent completion on four different zones in the well. The tubing performance successfully met the goals of the test, including being used for a frac. Operational problems associated with handling coiled tubing of this size are discussed, along with the lessons learned from using it. Future applications are also discussed.

INTRODUCTION

During the planning stages of ARCO Alaska's 1993 winter exploration program on the North Slope of Alaska, a question was raised as to the feasibility of coiled tubing completions. The specific question was whether coiled tubing could ever be practically used in the development of a North Slope oil field to replace conventional threaded and coupled tubing. To sustain the large flow rates of typical wells, large diameter tubing is required (3-1/2" or larger). Therefore, inquiries were made regarding the possibility of running 3-1/2" coiled tubing as the completion tubing on an upcoming exploration well. From the time the concept of using large diameter coiled tubing was first formulated in October 1992, to the successful completion of the project in April 1993, a spirit of teamwork and cooperation prevailed. All the mechanical

goals of testing the well were accomplished, and not one safety incident occurred, even though working conditions in the middle of the Arctic winter were extreme.

Since 3-1/2" coiled tubing had never been run in a well before, a number of technical questions had to be answered prior to committing to the project. Because the industry was poised and partially ready to take this step up to the 3-1/2" size, it was concluded that running this large diameter tubing was a reachable goal. Schlumberger Dowell was selected for this project to acquire the necessary equipment to perform the operation. ARCO management committed to the project in November 1992, and material orders were placed for this unique attempt at completing an oil or gas well.

A single permanent packer system was chosen for the completion. After the drilling rig was moved off location, a wireline unit set the packer (with a seal bore extension). Once the packer was set, the coiled tubing unit (CTU) was rigged up and a temporary working stand was set over the wellhead. A crane was used to pick up drill stem test (DST) tools along with a seal assembly for the packer. The DST tools were connected to the coiled tubing and run in the hole. Once the seals were engaged in the packer, the tubing was spaced out, cut off, and landed. At this point, the well was exactly like any other completion, and the production test was performed. After the test, the zone was isolated and abandoned. The coiled tubing in the well was then mechanically reconnected to the tubing on the reel, and spooled out of the well. DST tools were disconnected and laid down, and the process begun again on a new zone.

Figures at end of paper

DISCUSSION

One may ask why an exploration well was chosen over a standard development well in an existing field. Some of the reasons were:

1. Because of the active exploration program, there would likely be a shortage of completion rigs available.
2. The exploration wells being considered were to be ~7,000' straight holes (optimum for this test).
3. They were to be simple single completions (optimum for this test).
4. The completions, although permanent, would be used only for a few weeks.
5. Multiple production tests, if required, could be performed economically since the CTU could be released during flow periods.
6. The entire test would be finished within two months, and the project could be critically analyzed for practicality.
7. Since multiple tests would be performed, a learning curve could be established quickly.

The economics of using coiled tubing for testing the well versus a completion rig and conventional 3-1/2" tubing were compared. The plan at its inception was to use the coiled tubing on two wells. Given the proposed two well scenario, it was estimated that completing with 3-1/2" coiled tubing would be less expensive than a conventional completion rig. If the operation could be conducted in an orderly and timely fashion, the wells could safely be completed while evaluating the opportunity for future cost savings. As it turned out, only one well was available for this type of test, and the costs for that well were higher than anticipated.

The site of this well was approximately 25 miles west of the Kuparuk River Field, or about 60 miles west of the Prudhoe Bay Field.

EQUIPMENT DESCRIPTION

To accomplish the task of running 3-1/2" coiled tubing some specialized equipment had to be assembled. This included:

1. 3-1/2" Coiled Tubing Injector
2. 3-1/2" Coiled Tubing
3. 3-1/2" Coiled Tubing metal reel (15' diameter)
4. 3-1/2" Coiled Tubing Spooler to handle the reel of tubing
5. 3-1/2" Coiled Tubing connectors
6. 3-1/2" Coiled Tubing hanger*
7. 3-1/2" Coiled Tubing cutter
8. Special Welding Jig for 3-1/2" Coiled Tubing
9. Coiled tubing BOP larger than any presently in existence
10. Telescoping swivel sub
11. Temporary Work Platform

*This special hanger was not used after the first zone.

Figures 1 and 2 are pictures of the CTU and 3-1/2" reel trailer as it was rigged up on the exploration well. Figure 3 is a schematic of the arrangement of the equipment.

Working with Dowell, ARCO agreed to partially fund the coiled tubing injector that would be required for this project. The injector ordered is capable of handling coiled tubing sizes from 1" up to 3-1/2". This injector was critical for the project, and was installed on a conventional Dowell "Arctic Style" Coiled Tubing Unit.

Once a commitment was made to proceed with the project, ARCO ordered three spools of 3-1/2" coiled tubing. The plan called for the use one spool of tubing for each well, and one spool of tubing for backup. The 3-1/2" coiled tubing was manufactured by Quality Tubing, Inc. in Houston, Texas. The heaviest product that they offered was ordered. Although not exactly the same, the coiled tubing was compared to 3-1/2" 9.3 ppf L-80 thread and coupled tubing (See Table 1).

Because of shipping constraints (a railroad tunnel near Whittier, Alaska) the spool of tubing was limited to 15' in diameter. Each spool weighed approximately 60,000 lb, was seven feet wide and contained 6,500' of continuous tubing. The reel had to be mounted on a specially constructed spooler that could handle the weight of the tubing, and any weighted fluid the tubing might contain. The spooler sat on a low-boy trailer separate from the CTU, and powered by a hydraulic unit mounted on the trailer. This hydraulic unit and the spool holding the reel of tubing was controlled by a remote operating cab (ROC) (See Figure 4). Some other specialty tools required included a 3-1/2" tubing cutter, a 3-1/2" tubing swivel sub, and several connectors that crossed over from the coiled tubing to a 3-1/2 EUE 8rd pin.

This connector was made up of three pieces. Because of its simplicity, it worked extremely well. Modifications necessary from the basic design included adding a groove for poly-pack seal rings, repositioning of the set screws, and smoothing of the sharp edges on the shoulders of the tool. The connector was subjected to full scale testing prior to the job. This included pressure testing to 10,000 psi, and then pull testing it to 114,000 lb tension. Since they were not damaged by the test, they were used on the well. The first was used on the bottom of the coiled tubing to connect the DST tools. The second was used at the top of the coiled tubing to connect to the tubing hanger on the second production test.

A special tubing head was ordered to hang the coiled tubing. However because the wraparound slip segment was difficult to retrieve after the first week of service, that tubing head was replaced with a mandrel type tubing

hanger. This allowed use of a standard Kuparuk River Unit 5,000 psi tubing head. This system worked very well.

OFFSITE EQUIPMENT TEST

All the necessary equipment arrived on the North Slope by mid February 1993. In anticipation of a learning curve for handling tubing of this size the first time, the complete operation was rigged up on a well in the Kuparuk River Unit that was to be plugged and abandoned. This well, the UGNU SWPT #1, had 10-3/4" production casing with a plug set at approximately 2,900'. A split well house was used to provide protection from the cold weather. Several days were spent developing the proper technique for "threading" the injector with the 3-1/2" coiled tubing. Because there were no associated charges for this operation other than for heaters, light plants, and related miscellaneous equipment, ARCO costs for this trial were held to a minimum (approximately \$11,000). The better part of eight days (day shift only) was spent working on stabbing the tubing in a workable manner. Three of the eight days were spent in the shop making minor modifications. Several things were learned from this trial run:

1. An orderly manner of stabbing the tubing was worked out.
2. A modified fishing spear was constructed to retrieve the tubing.
3. Several safety deficiencies (both equipment and operational) were noted and corrected before the actual operation took place.
4. Difficulties with the hydraulic power on the spooler were addressed.

Crews familiarized themselves with completely new equipment without having "live well" conditions or costs pushing their efforts. This "dry run" was extremely valuable in saving time on the first actual completion. With unusual equipment like this, the crew came up with many useful ideas to accomplish specific tasks in better ways.

THE OPERATION

After the exploration well was drilled and the 7" production casing was set, the drilling rig remained in place to make a bit and scraper run before moving to its next well. A wireline unit ran the cased hole logs, and set a permanent packer with tubing conveyed perforating (TCP) guns attached. Once the rig was off location, the CTU was brought in. The "move-in rig-up" of the unit and "nipple up" of the blow out preventors (BOP's) took place quickly. The operation was slow going during the first two production tests, but by the time the third and fourth tests were performed, the pace equaled a normal completion rig's timing for finishing each task.

A skeleton procedure of the completion plan is attached. See Table 2.

The CTU and special trailer with the 3-1/2" coiled tubing spool were rigged up on opposite sides of the well. It could have been rigged up a number of different angles to the well, including having the coiled tubing trailer in front of the CTU with the tubing strung over the CTU to the injector and well.

Even after the practice run on the P&A well the previous month, the crews still had difficulty handling the 3-1/2" coiled tubing as it was stabbed into the injector. The ambient temperatures were 10°F to 20°F below zero. When the wind came up the wind chill factors between 70°F and 100°F below zero made working conditions miserable. Although a well house was on location, the crews chose to work without it because it restricted their view of the operation. Some form of shelter needs to be provided on future jobs. A specially built portable walled unit that would allow tools to be picked up from the top by a crane is necessary.

The BOP stack consisted of two sets of rams and an annular. (See Figure 5):

The production casing in this well was 7" 29 ppf L-80 BTC. Therefore 7-1/16" rams were necessary so that tools could be run through the lower BOP's. Being full bore, they also allowed the mandrel type tubing hanger to be used. A full opening manual master valve was installed below the lower BOP to provide a level of safety while all tubing and tools were out of the well. This valve could have been replaced by a set of blind rams. The 5-1/8" size of the upper combination BOP was chosen so it could handle the 3-1/2" tubing and most smaller tools, although it really should have been 7-1/16" also. This configuration would allow a modified snubbing operation to take place if necessary, though the plan was to always have the well dead during any pipe running operations. If pressure had been detected while tripping out, the test string could be run back to bottom and kill weight fluid circulated until the well was dead.

The upper BOP was a combination 5-1/8" BOP to keep the stack height to a minimum. It had a blind-shear ram in the top section and a pipe slip-ram in the bottom section. This new BOP worked extremely well even under Arctic conditions. The lower BOP was a set of 7-1/16" 5,000 psi rams. The 10,000 psi annular (different manufacturer) had some sealing problems above 2,000 psi under Arctic conditions.

A 10' by 10' working platform was constructed to be level with the top of the 7-1/16" BOP. This platform was later expanded to 14' by 14' so that the casing crew would have adequate working room for their hydraulic tongs.

Whenever the tubing was run in or out of the hole, the BOP stack was separated at the flange on top of the 7-1/16" pipe rams. This allowed the packer and downhole

tools to be run in the well using a temporary bowl and slips set on top of the lower BOP. A small crane (42 ton) was used to pick up the downhole tools and run them in the hole. The casing crew made the connections in the downhole test string using tubing tongs temporarily rigged up on the work platform. While tools were being run, the injector, annular, and 5-1/8" BOP's were raised to the top of the mast out of the way of the work.

A telescoping swivel sub was run at the top of the DST tools just below the connector back to the coiled tubing. This was necessary so the connector could be completely installed on the coiled tubing prior to making it up to the DST tools. The swivel sub allowed this last connection to be made without rotating the entire string of DST tools.

The packer selected for this well was a permanent type with a seal bore extension. This type of packer was selected because:

1. It could be run and accurately set on wireline.
2. No rotation is required to "unsting" from the packer.
3. The packer would become part of the permanent abandonment of the well once testing of the zone was completed.
4. The seal assembly allowed tubing movement during a frac.

Since a typical CTU does not have a precise way of measuring depth, the packer was set on wireline. Some of the zones were perforated with tubing conveyed perforating (TCP) guns run attached to the packer. Other zones were perforated with through tubing guns. (See Figure 6).

When through tubing perforating guns were run, the packer assembly was very simple:

1. Model FB-1 Permanent Production Packer
2. 15' Seal Bore Extension
3. X-Nipple (ID = 2.25")
4. 1 Jt Tbg
5. Wireline Entry Guide

The seal bore extension was necessary to allow for tubing movement during fracture treatments. There was a concern as to how difficult it would be to stab the seal assembly into the packer, without rotating the tubing. However, the assembly went in with no problem at all. A positive indication was seen on the weight indicator as each of the four sets of seals engaged the seal bore extension. A special racheting muleshoe was available if the standard muleshoe would not engage the packer, but it was not necessary in this straight hole. It might be necessary in directional holes in the future.

The second, third, and fourth runs were completed as follows: Once the fifteen feet of seals were fully engaged in the packer, the tubing was raised one foot. It was

marked above the injector, and pulled up approximately eight feet. This eight feet was the distance from the tubing head to the top of the lower BOP. The lower set of pipe-slip rams was closed to hold the tubing. Once all the string weight was set on the lower BOP slip rams, the flange from the lower BOP to the spool was disconnected and the injector (with 5-1/8" BOP) was raised several feet out of the way. The tubing was cut with the large tubing cutter. A connector was attached to the tubing, and the mandrel tubing hanger was threaded onto the 3-1/2" EUE 8rd pin of the connector. A different connector (or spear) was used to temporarily attach the top of the tubing hanger to the coiled tubing up in the injector. The injector and upper BOP's were slowly lowered back onto the lower BOP and nipped up again. Then the injector picked up the weight of the string, as the lower pipe-slip rams were released. The tubing hanger was then lowered and landed in the tubing head. Once it was landed, the BOP spool could be disconnected again and the temporary connector removed from the top of the tubing hanger. The lower BOP's were nipped down, and the test tree nipped up.

At this point, the 3-1/2" CTU could have been released, since it would not be needed it again until this production test was over. The original plan was to change the blocks in the injector over to the 1-3/4" size that would be needed for frac clean outs or nitrogen lifting of the well. However, the parts to do this quick change over did not arrive in time for the job. Therefore Dowell furnished a second CTU with the smaller tubing for the frac clean out and loading the wellbore with fluids.

As mentioned earlier, another style of tubing hanger was tried on the first completion. It was a conventional packoff assembly that had segmented slips held in place with lock down pins. Although it performed well during the production test, at the end of the test, there was difficulty in removing the packoff from the hanger. It kept slipping on the tubing as the pipe was pulled. Pressure had to be applied to the tubing annulus to unseat the packoff and remove it from the tubing head. This could have been a serious problem if the packoff had been in place for a long time, so the decision was made to switch to the mandrel type tubing hanger.

Running in the hole with the coiled tubing was very easy. There were no problems at all while tripping the pipe in or out of the hole. Running in rates of 50 to 70 feet per minute, and retrievals at 70 to 100 feet per minute were easily achieved.

On the first attempt to retrieve the coiled tubing from the well, a double spear was used. This was two 3-1/2" typical fishing spears that had been welded to a six foot section of coiled tubing. The spear was stabbed into the coiled tubing in the well and into the coiled tubing in the injector on the CTU. Everything worked fine as the coiled tubing was pulled out of the well, until the spear began to be spooled onto the reel. The weld at the base of the spear split and began leaking fluid. The weld did not fail

completely, but it was determined that a dangerous situation existed, and therefore the operation was stopped until this damaged section could be secured. It was welded to the tubing wrap next to it. The failure was caused because the spear was too stiff to allow bending around the spool. Experiments with bending the spear on a test stand in the shop before bringing it out to location indicated that it would perform satisfactorily. However, under actual conditions, the coiled tubing next to the spear bent excessively trying to compensate for the stiff section that did not bend. That extreme bend at the weld area resulted in the failure.

Because of the spear failure, it was decided to butt weld the pipe the next time it had to be pulled out of the well. The welding was a simple TIG (Tungsten Inert Gas) process that used low heat. Actual welding took only 45 minutes. A welding jig was used to align the tubing, and chill blocks were installed to help dissipate the heat evenly (See Figure 7). A locator ring was used to help the alignment of the tubing. The welder made two passes, then wrapped the weld with a welding blanket for 30 minutes to prevent it from cooling too rapidly. The chill blocks were then removed, and the weld was ground flush. After the welding jig was removed, we noticed that the tubing was slightly mis-aligned. Also, the adjusting screws on the alignment jig had scarred the surface of the tubing near the weld, and BOP slip marks were noticed within six inches of the weld. Because of these deficiencies, this weld was cut out before the tubing was run in another well. After the welding is finished, the pipe can be pressure tested if necessary.

The specially constructed gooseneck for the 3-1/2" coiled tubing was only partially used. The tubing did not want to follow the shape of the gooseneck, so most the rollers were left open and out of the way.

While preparing for the trip out of the hole from the last test, the mast that supported the injector trolley bowed enough for the trolley to jump its tracks. This allowed the trolley assembly to swivel and slip down a few feet. There was a lot of banging of metal as the trolley jumped the track, but no real damage was done, and no one was hurt. Dowell had the mast manufacturer make modifications to the trolley system and mast so that this would not happen again. There was no damage to the well or wellhead.

During the 30 days of continuous operation, a cumulative total of 98 hours (4 days) of lost time was experienced due to trouble directly related to the 3-1/2" CTU. Considering the completely new aspects of this operation, that amount of downtime was minor.

A skeleton procedure of how the operation would be handled today is attached. See Table 3.

During a fracture treatment on one zone, the tubing pressure at one time went to 8,900 psi (2,500 psi annulus pressure). The high pressure occurred because of a

screen out. Tubing damage was a concern because tubing movement calculations had predicted that the tubing would be corkscrewed (plastically deformed) at the bottom due to the instantaneous pressures. However, since coiled tubing is manufactured from low carbon steel that gives it strength and ductility, it withstood the higher stresses that standard thread and coupled tubing could not. There was **no** damage to the tubing.

COST ANALYSIS

The tubing cost \$8.43 per foot in Houston. To that cost we added shipping (\$1.50/ft), spool and fittings (\$1.32/ft), for a total cost on location of \$11.25 per foot. This compares favorably with the internally plastically coated 3-1/2" 9.3 ppf L-80 thread and coupled tubing that we typically carry at approximately \$10.25 per foot delivered to location. ARCO's investment in specialized handling equipment (\$210 M) will pay dividends on future wells since it can be used again. Other costs spent in development of unique equipment were minimized (\$57 M). Of that, \$27 M was services and \$30 M was equipment that is reusable. One of the biggest costs was the extra equipment that was necessary because a rig was not on location. Since this was a new technique, several of those daily costs will be reduced in the future. For instance, because of the remoteness of the well, the crane was on site all the time, although it was only used intermittently. Tanks could have been used instead of having the vacuum trucks standing by 24 hours a day. The casing crew costs were necessary since Dowell did not have any equipment for making up standard connections, however this equipment is available today. A crew of three roustabouts was on location almost everyday. Of course, for the remote location, a camp was necessary for the personnel. If operations were conducted anywhere near the base facilities on the North Slope, the camp would not be required.

Before the project started, comparisons were made to expected costs to a completion rig. ARCO would have saved up to \$190 M total on two wells. If only one well was to be completed, the cost was estimated to be approximately \$10 M over a completion rig. However, major cost items **not** foreseen were:

1. Crane	\$ 95 M
2. Camp Charges	\$50 M
3. Work Platform	\$10 M
4. Spears/Connectors	\$20 M
5. Special BOP Parts	\$10 M
6. Special Tbg Cmt Retainers	\$35 M
Total	\$220 M

Post analysis revealed that after crediting the well with the reusing the tubing on a future well, the costs for the operation were approximately \$290 M more than a completion rig would have been. However, if the same project was done today, the costs would be about the same as a completion rig, with the economics favoring the CTU completion on a longer term production test.

The CTU completion would have been less expensive than a drilling rig carrying a daily cost of \$30 M per day gross.

SAFETY ISSUES

Safety and well control were of prime concern during the operation. Because the uncertainty of how all the equipment would work this first time, several levels of safety were required for all operations. All trips in and out of the hole were planned with open perforations being isolated. This meant a plug in a profile below a packer, or a cement plug set to seal off the zone. In addition, kill weight fluid was always left in the hole while tripping. If an unforeseen situation occurred that required tripping with a zone open, the kill weight fluid and BOP equipment would provide the multiple levels of safety. If the well began flowing, the tubing could be stripped back to bottom and the well to be circulated until dead. Using coiled tubing gives an operator the ability to circulate at all times while the tubing is connected to the spool.

All crews participated in safety and environmental awareness meetings on location.

An additional reason for preferring the mandrel type tubing hanger was that it provides the ability to set a back pressure valve in the tubing head while the tree was being installed or removed.

Welding on a live well, if necessary, could be accomplished only if the well had a plug of some kind downhole, and there was kill weight fluid in the wellbore.

The weather was extreme. As discussed earlier, some type of shelter for the crew on the well "floor" must be provided.

CONCLUSIONS

There was a very steep learning curve during this project. As the crews familiarized themselves with the new equipment they quickly gained confidence in handling it. There is still a lot to learn, and numerous improvements to be made, but it can be done.

Upside considerations for using coiled tubing are numerous. The biggest benefit would be the combination with electrical submersible pumps (ESP). This project was a major step toward that goal.

Benefits that favor using 3-1/2" coiled tubing for a completion include:

1. Lower workover costs for simple workovers.
2. Lower production facility costs if ESP's are used.
3. Flexibility of testing program with CTU.

4. Testing of exploration wells longer in the winter ice season
5. Lower exploration well testing costs than using a drilling rig.

Two firsts were accomplished during this project:

1. The first time that 3-1/2" coiled tubing had ever been used in a well.
2. To the author's knowledge, this is the first time that coiled tubing had ever been used as a frac string.

There is a real need for development of better handling tools for larger coiled tubing sizes. Connectors that are more easily attached would save time. Similarly, a quick stab full opening valve that would connect to 3-1/2" coiled tubing is needed.

Overall this project was very successful. The 3-1/2" coiled tubing performed up to expectations in every way. After the expected start up problems with first time use, the crews handled the tubing cost effectively. This project set the stage for running this tubing as a permanent completion on other wells on the North Slope of Alaska, and anywhere else in the world for that matter.

RECOMMENDATIONS

Further evaluation of this type of completion is warranted. At this writing ARCO Alaska, Inc. has run this type of completion on two simple completions in the Kuparuk River Unit on the North Slope. The economics are favorable for this being a viable completion technique in high cost area operations. Refinement and optimization of the procedures and methods used has the potential to make 3-1/2" coiled tubing completions economic for lower cost area operations.

Since it was demonstrated that 3-1/2" coiled tubing is a usable product, and since coiled tubing drilling is rapidly evolving, there will be a place for 3-1/2" to have an impact in the shallow well market, especially in horizontal wells.

ACKNOWLEDGMENTS

The authors thank ARCO Alaska, Inc. and Schlumberger Dowell for the opportunity to explore and implement new technology.

Table 1

Comparison of Properties

	Grade	OD	ID	Drift ID	Wall Thickness	Weight Per Foot	Burst	Collapse	Tensile Strength to Yield
3-1/2" Coiled Tubing	QT-800	3.500	3.094	2.867	0.203	7.148	10,250 psi	6,950 psi	168,210 lb
3-1/2" T&C Tubing	L-80	3.500	2.992	2.867	0.254	9.300	10,160 psi	10,530 psi	142,460 lb

Table 2**Basic Procedure as run**

Before CTU arrives on location, have wireline unit set packer with tubing conveyed perforating (TCP) guns in hole (TCP guns optional).

1. Move in and rig up CTU with 3-1/2" coiled tubing.
2. Nipple down tree and nipple up 7-1/16" full bore master valve, and 7-1/16" BOP.
3. Rig up working floor and hydraulic tongs on top of 7-1/16" BOP. Make up and run in hole seal assembly and DST tools. Nipple up CTU BOP system composed of spool, 5-1/8" BOP (shear rams and pipe rams), 5-1/8" annular. Connect 3-1/2" coiled tubing.
4. Run in hole with assembly on coiled tubing to packer.
5. Space out. Hang off 3-1/2" coiled tubing in tubing pipe slips. Cut tubing, attach tubing hanger and land in tubing head. Nipple up test tree.
6. Rig down CTU. Perforate. (Drop bar if TCP guns were used.)
7. Perform production well test. Frac as necessary.
8. When test is finished, rig up CTU with 1-3/4" coiled tubing, kill and squeeze off the producing zone. Leave cement across perforations. Circulate hole with kill weight brine.
9. Reconnect tubing (using weld or connector) and pull the 3-1/2" completion. Lay down DST tools.
10. Rig-up wireline unit. Set plug in packer.
11. Run in hole with a permanent packer and set above next zone to be tested. Run in hole with a 3-1/2" completion assembly as above. Repeat operations as above for remaining zones.
12. If no other zones are to be tested, plug and abandon the well.

Table 3**Basic Procedure if it were done today -**

Before CTU arrives on location, have wireline unit set packer with tubing conveyed perforating (TCP) guns in hole (TCP guns optional).

1. Move in and rig up CTU with 3-1/2" coiled tubing.
2. Nipple down tree and nipple up 7-1/16" BOP (Blind / Shear rams over pipe and slip rams).
3. Rig up working floor and hydraulic tongs on top of 7-1/16" BOP. Make up and run in hole with seal assembly and DST tools. Nipple up 7-1/16" annular just below injector head. Connect 3-1/2" coiled tubing.
4. Run in hole with assembly on coiled tubing to packer.
5. Space out. Hang off 3-1/2" coiled tubing in tubing pipe slips. Cut tubing, attach tubing hanger and land in tubing head. Nipple up test tree.
6. Rig down CTU. Perforate. (Drop bar if TCP guns were used.)
7. Perform production well test. Frac as necessary.
8. When test is finished, rig up CTU with 1-3/4" coiled tubing, kill and squeeze off the producing zone. Leave cement across perforations. Circulate hole with kill weight brine.
9. Reconnect tubing (using weld or connector) and pull the 3-1/2" completion. Lay down DST tools.
10. Rig-up wireline unit. Set plug in packer.
11. Run in hole with a permanent packer and set above next zone to be tested. Run in hole with a 3-1/2" completion assembly as above. Repeat operations as above for remaining zones.
12. If no other zones are to be tested, plug and abandon the well.

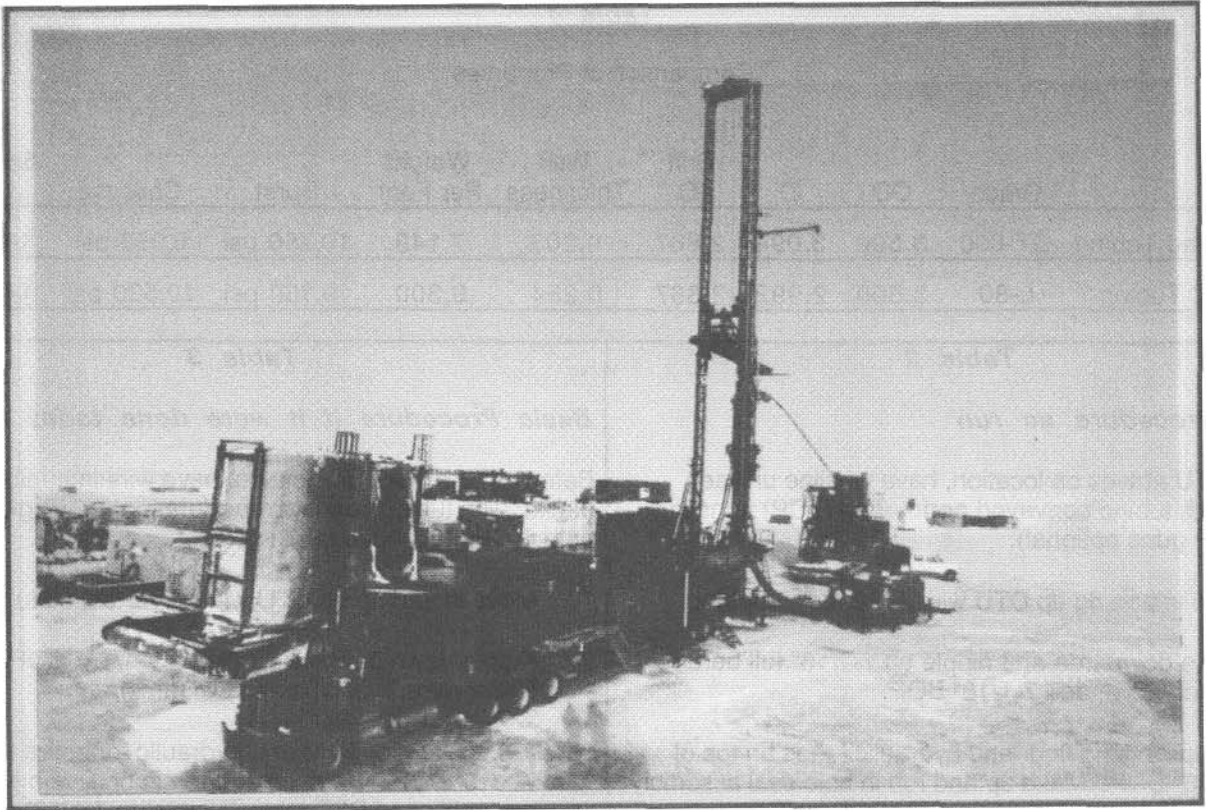


Figure 1
Dowell "Arctic Style" Coiled Tubing Unit

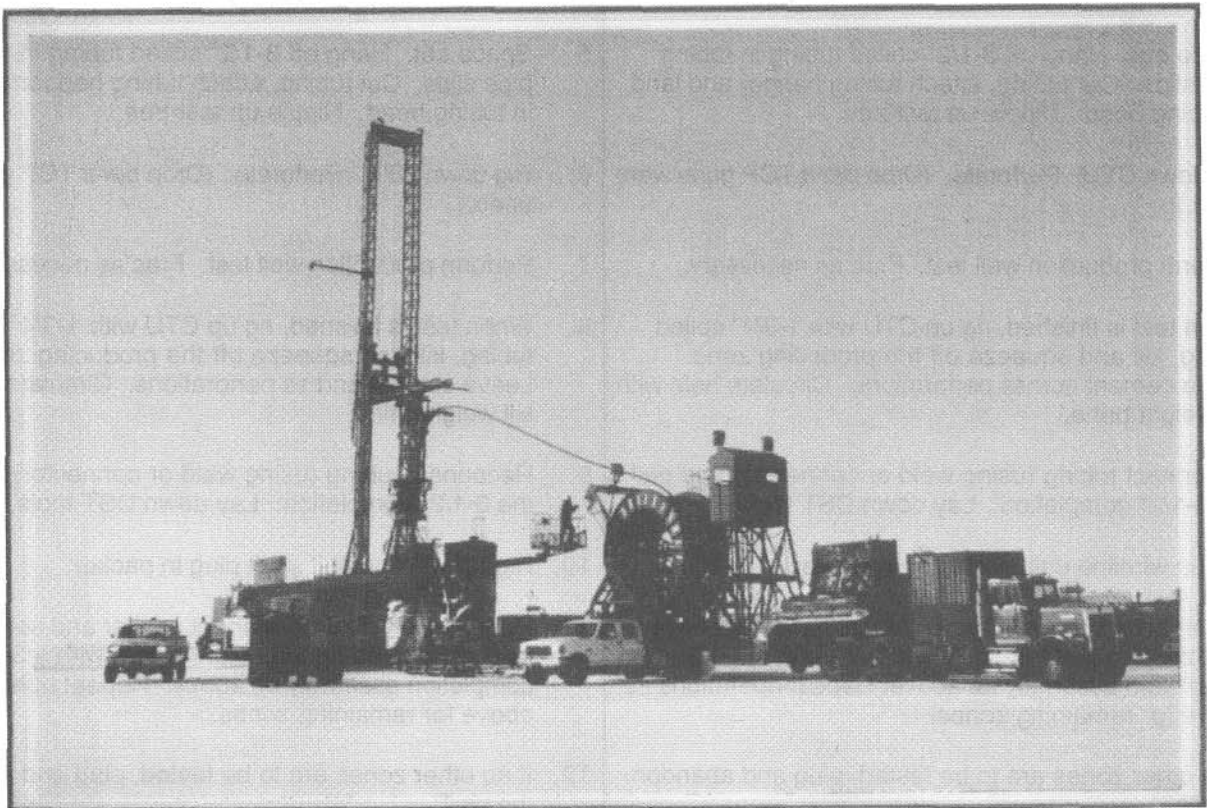


Figure 2
3-1/2" Coiled Tubing Trailer Rigged Up on Location

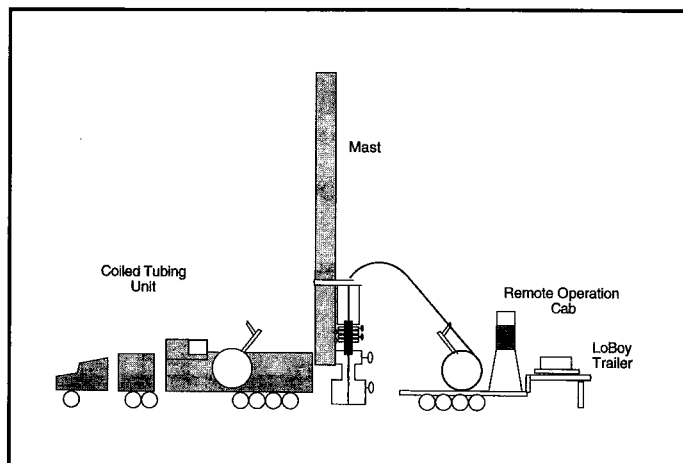


Figure 3
Schematic of the Main Equipment

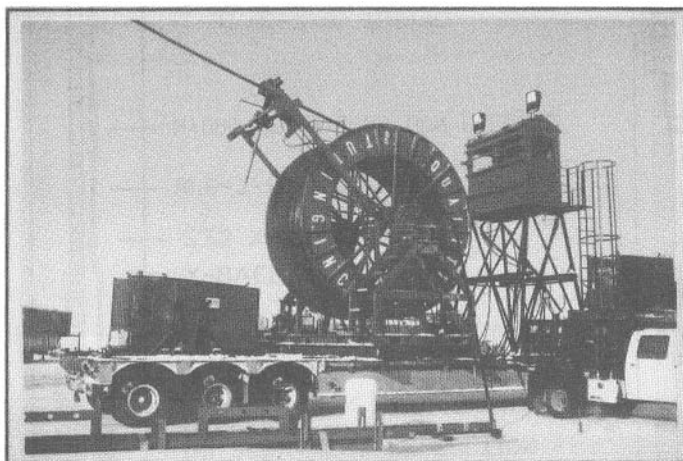


Figure 4
3-1/2" Coiled Tubing Reel and Remote Operating Cab

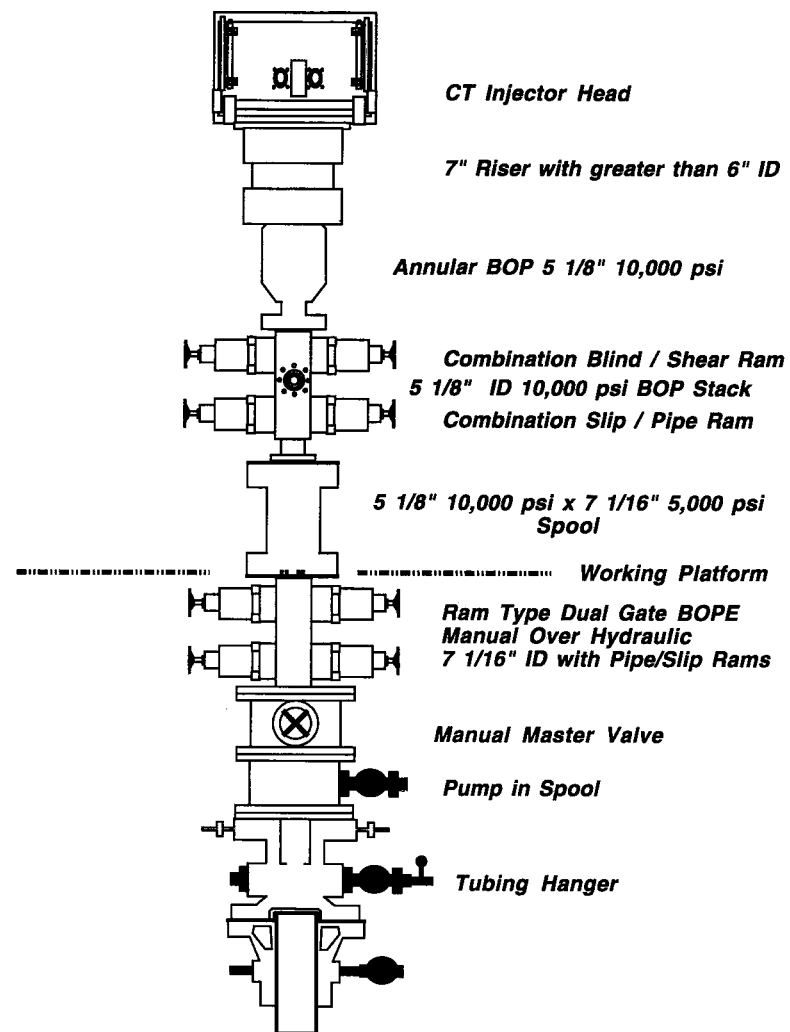
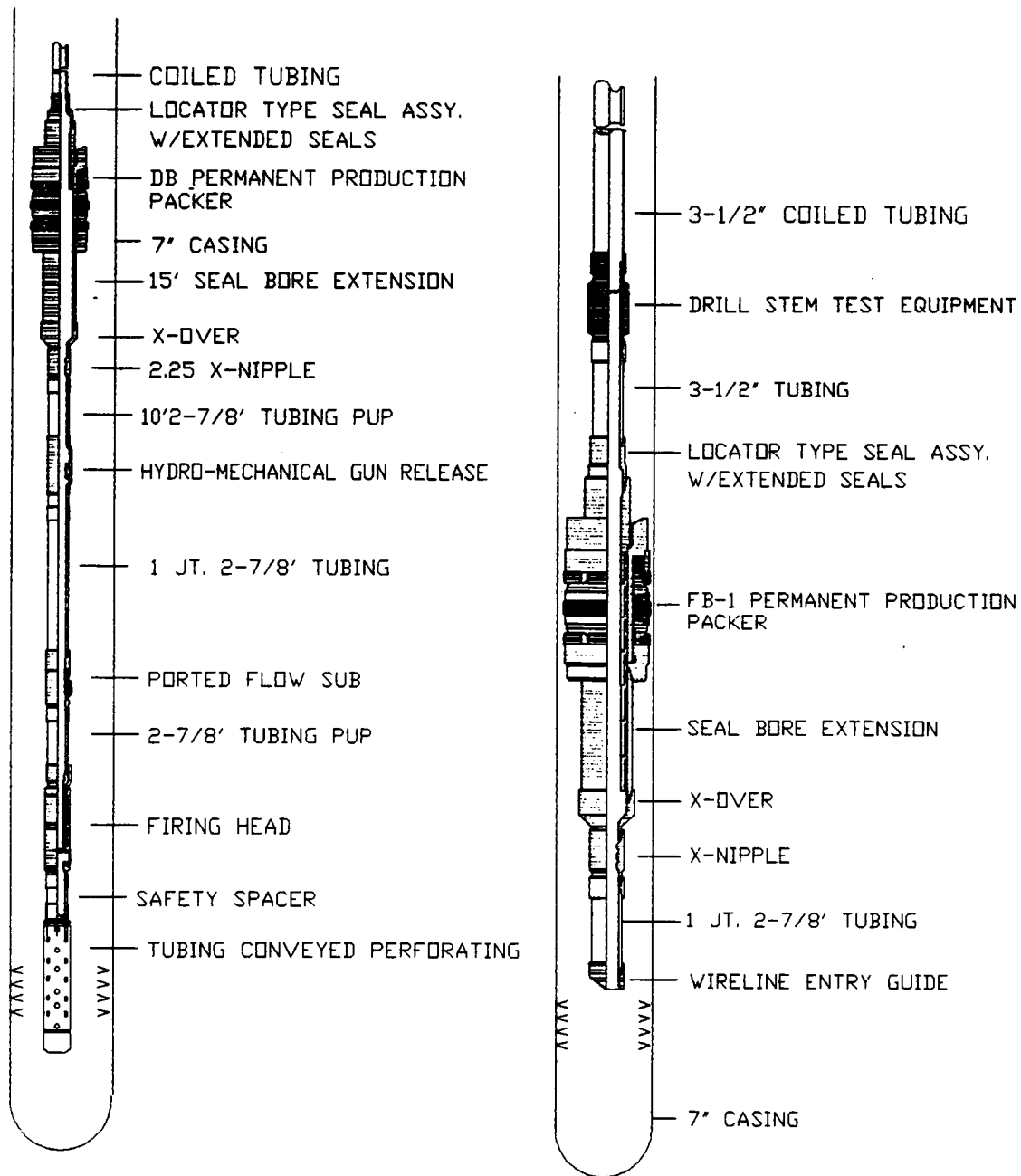


Figure 5



Packer Setting Options with and without Tubing Conveyed Perforating Guns

Figure 6

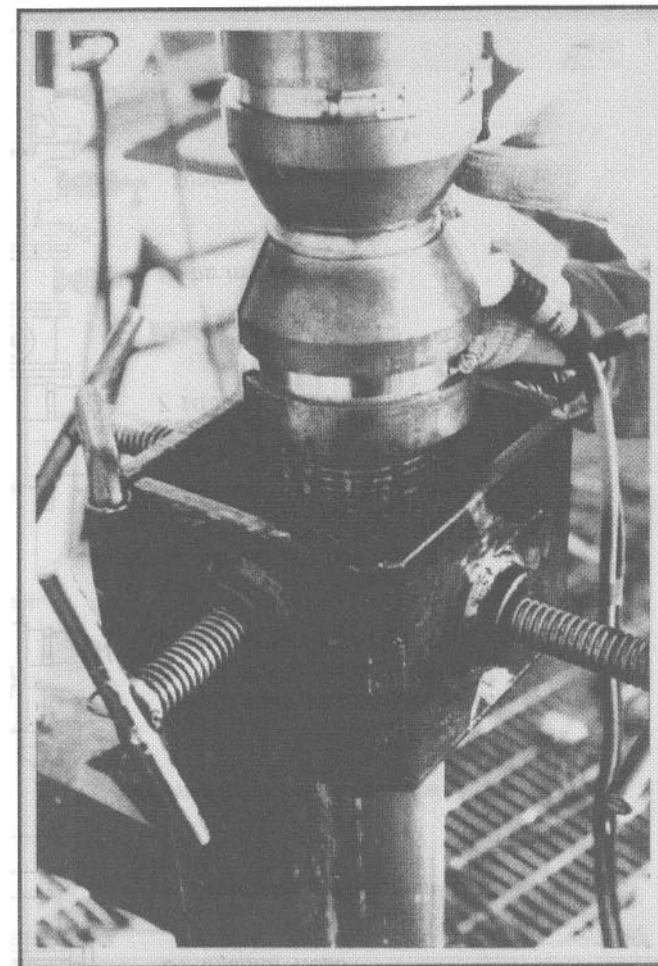


Figure 7

Welding Jig and Chill Blocks Around Tubing Weld